Appendix II

DELMARVA Supplemental IRP Report

Comparative Costs and Risks of Alternative Managed Portfolios for Delmarva's RSCI SOS Supply

Frank C. Graves
The Brattle Group

May 20, 2008

This evaluation was conducted using an enhanced version of the model described in Delmarva's March 5, 2008 IRP filing at pages 78-103 The model applies industry-standard risk simulation techniques grounded in financial economic theory. Empirically, it is based on recent (April 2008) financial market data about expected future costs and volatilities for electric power and natural gas prices in eastern PJM, as well as demand and wind speed uncertainty. The model is applied separately to on- and off-peak energy requirements for Delmarva's RSCI customers, net of amounts served by DSM programs and any ongoing full service requirements contract. The analysis was performed on a planning year basis (June 1 through May 31) for the period June 1, 2009 to May 31, 2011 and on a calendar basis for 2014-2016.

Portfolio alternatives are evaluated along two dimensions: expected cost and risk. Risk is captured as the range of possible annual cost of service outcomes across 1000 Monte Carlo simulations for each future year. Monthly price levels in each draw are converted to hourly shapes using historical PJM LMP price patterns for a typical week in each month. Wind resources are simulated using hourly output patterns specific to each month derived from historical data on local wind speeds and publicly available data on turbine characteristics. These hourly profiles are used to simulate hourly revenues from wind resources, the economic dispatch of gas-fired CTs, and the net cost of spot purchases/sales needed to match hourly supply and demand.

Brattle applied this modeling framework to a variety of portfolio compositions:

- **ManagedPortfolio(the Base Case)** - A portfolio of annual fixed-price base-load contracts, monthly forward contracts purchased in installments, and spot purchases as described in more detail below. When renewable resources are not combined with the portfolio, Renewable Energy Credits (RECs) are purchased at forecasted annual prices.
- **Managed Portfolio plus Land-Based Wind (Scenario 1)** – The above Managed Portfolio plus wind resources similar to what was offered in Delmarva's recent RFP for

land-based wind resources as needed to satisfy RPS requirements. These resources provide only energy and RECs, without capacity or ancillary services.

- **Managed Portfolio with Land Based Wind plus a Regulated Asset (CT) (Scenario II)** – The Managed Portfolio with Land Based Wind plus a cost-based 100MW peaker in Delaware for local reliability benefits, plus dispatchable energy and capacity.
- **Managed Portfolio with Land Based Wind and a Long Term Contract (Scenario III)** – The Managed Portfolio without the base-load, annual fixed contracts, but instead with energy and capacity from a 10-year fixed-price contract, simulated at the nominal levelized capital and operating costs of a new gas-fired combined-cycle (CC) unit. This contract provides energy just during on-peak hours, on a cost-basis at the ten-year average forward price of natural gas.
- **Managed Portfolio with BlueWater Wind (BWW) (Scenario IV)** – From June 2014 and beyond, the Managed Portfolio plus up to 300MWh/hour of energy, 90MW of capacity and RECs, from the proposed 450MW offshore wind facility.
- **Managed Portfolio with BWW Hybrid (Scenario V)** – As above, plus Conectiv Energy CTs for 195MW of unforced capacity (UCAP) and backup energy from two 100 MW LMS-100 CTs.

In addition Brattle modeled two "extreme" portfolios to provide a further basis of comparison:

- **All Spot** – All RSCI load satisfied with spot market purchases, including energy, capacity, ancillary services and RECs.
- **All Fixed** – All expected RSCI requirements served with a one-time purchase of an annual fixed-price forward contract made twelve months in advance of the delivery year, with differences between actual loads and this contract's volumes cleared in the spot market.

In each of the portfolios involving wind or gas-fired generation resources, those physical resources are modeled as a financial supplement to the costs and risks of the Managed Portfolio (without RECs, when wind resources are used). That is, these resources are dispatched against the projected spot price of power in the region of PJM where they reside (reflecting likely PJM least-cost dispatch), rather than being dispatched to satisfy any specific portion of the Delmarva load. Their financial effects are captured in each Monte Carlo draw of market conditions and then are added to the corresponding simulated Managed Portfolio costs, in order to get the net effect on customer costs and risks.

Findings

- Portfolio design requires consideration of two issues. The first is *ex ante* uncertainty over what the future, realized price of power could be under alternative designs. This is true economic risk, which can be reduced by earlier, fixed-price procurement of significant portions of the expected load, *i.e.*, by hedging. The second, somewhat offsetting consideration is that there can be undesirable consequences of hedging large quantities forward for long periods of time, manifest as *ex post* costs and "regret" over the chosen strategy. Specifically, long-term hedging at a fixed price can result in SOS customers paying prices higher than then-current market prices, leading to heightened possibilities of customer switching away from SOS service. Fixed, long-term commitments also involve credit risks and associated cash management costs for the buyers and sellers, and a long-term purchase obligation by the utility may be treated as imputed debt by bond ratings agencies. Utility investors may have low confidence in regulatory approvals for cost recovery of long-term purchases, out of concern that those contracts could have higher costs than market alternatives at some future review date. A managed portfolio can balance these *ex ante* and *ex post* concerns by making fixed-price resource commitments in installments over time, and by including some spot purchases in the supply plan.

- A portfolio offering a balanced exposure to *ex ante* risk and *ex post* regret, and that would be acceptable to Delmarva (though also amenable to refinement as a result of proposed PSC workshops with the collaborative working group and Commission approval), is as follows:
  - A base-load layer of 100 MW of all-hours energy at a fixed annual price equal to the market price of forward contracts;
  - A "dollar cost averaging" (DCA) layer of contracts with fixed monthly prices, purchased forward in installments beginning approximately twelve months in advance of the delivery year, for up to 90% of total on-peak requirements, subject to procuring the power in the standard, 50MW minimum block size;
  - Spot purchases in the delivery month for the remaning on-peak RSCI loads, and all of the off-peak loads not served by the 100MW fixed annual block
  - RECs are purchased as needed to satisfy annual renewable energy requirements and ancilliary services assumed to be purchased from PJM at a price increasing from $2 to $3/MWh between 2009 and 2016.
  - Capacity is modeled as being purchased in PJM's RPM markets at prevailing zone prices through 2011. In 2014-16, capacity is modeled at ICF's forecasted price, which is approximately equal to the cost of new entry.

  The horizons of forward purchases in this portfolio are also consistent with wholesale market liquidity.

- In the near term (2009-2011), the expected costs of all of the evaluated portfolios are fairly close, with a slight advantage for the Managed Portfolio with a Regulated Asset (CT). In terms of overall risk, the strategy with the smallest 10^{th} - 90^{th} percentile range of annual costs is the Managed Portfolio plus Land-Based Wind and CT strategy .
  - The peaker is economically attractive by itself in about ¾ of the Monte Carlo outcomes in the near term, and it reduces risk by providing electricity at gas-based costs (below spot electric prices) in those hours when it is dispatched.
  - The land-based wind resources raise portfolio costs slightly, because they tend to produce more power at times when it is less valuable in PJM-West (by about $15/MWh) than the contract price being charged to Delmarva. However, they defray about $10/MWh in REC costs, and they reduce overall risk. The risk reduction occurs because most of the wind revenues are incurred in off-peak periods, when they do not face a large range of potential spot prices, and because the contracts include substantial fixed costs.

- Replacing the 100MW base-load fixed-price block of forward power with a long-term, 10-year firm contract slightly increases average costs by about $3/MWh compared to the Base Case. This contract was simulated as providing capacity plus on-peak energy from a new combined cycle (CC) unit, with off-peak needs met in the spot market. As a result, it slightly increases overall portfolio risk.

- By 2014-16, the forward curves for electricity do not shift much, so the rank ordering of costs and risks among portfolio alternatives is much the same. Because RECs have become more expensive (roughly $15/MWh vs. about $10 in 2010), the land–based wind projects are a bit more attractive. Again, land-based wind plus CT is also the lowest risk of the cost-competitive alternatives, but both the cost and risk advantages are modest compared to some other strategies.

- The BlueWater Wind (BWW) resources are strongly uneconomic and unattractive compared to all of the other alternatives. The costs for just the wind portion of the proposed contract are about $60/MWh above the market value of the capacity, energy and RECs that the plant would produce, so rolling it into the Managed Portfolio would raise its average costs by about 30%. Including the proposed Conectiv Energy CTs for backup energy and capacity makes the average portfolio cost a bit higher, and the CTs produce only slight energy savings for Delmarva. [1]

- All of the above findings, except for the extreme unattractiveness of BWW, are probably within the limits of precision surrounding key assumptions in the modeling, such as load levels, DSM penetration, and future prices for natural gas, capacity, RECs, and CO2. Accordingly, there is no strong basis for preferring one or the other of these strategies on the basis of modeling results to date. Further detailed study can test the reasonableness of key assumptions, and evaluate operational and administrative reasons for preferring one strategy over another. Once a portfolio is implemented, it needs to be monitored and evaluated on a regular basis as expectations, uncertainties, and technological opportunities change.

- When high and low future market scenarios driven by CO2 prices and natural gas scenarios are considered, the relative attractiveness of alternatives is unchanged. The BWW alternatives have higher expected costs in the low-priced scenarios than any other strategy in the high-priced scenarios.

- Any strategy that involves Delmarva committing to a long-term resource, such as a 10-year supply contract or ownership of a generation plant, should be entered only in conjunction with a policy about how to assure reliable cost recovery for those resource commitments. In particular, a mechanism for tracking unrecovered costs and ultimately assigning them to a non-bypassable surcharge will be important.

---

1 As explained later, the BWW resources provide a superficial benefit of reducing risk, in that including them significantly reduces the $10^{th} - 90^{th}$ percentile range. This is not a benefit. It occurs because the fixed costs of BWW are so high that they actually dampen total risk per MWh -- but in so doing they raise the average by 30%.

Tables 1-3 present a summary of the expected costs and the risk ranges from simulations of each of these strategies.

Detailed Discussion of Method and Results

Description of Models

Brattle Portfolio Risk Model – This model is an extension of the model that was used to demonstrate the risk characteristics of a hypothetical 2008 RSCI portfolio in the March 5, 2008 IRP Update filing by Delmarva. That portion of the Delmarva IRP report described the analytic foundations of risk modeling of an electricity supply portfolio, for on-peak energy only. For the present application, that model has been updated and extended in the following ways:

- Updated forward prices and implied volatilities from traded options, effective April 9, 2008; Figures 1a and 1b show the on-peak forward prices, quoted volatilities, and associated statistical fits for the volatility function used to create Monte Carlo draws in the simulation model.
- Off-peak periods added, at forward prices equal to the historic ratio of off- and on-peak spot prices times quoted on-peak forward prices, and with volatility equal to the on-peak quoted volatilities times historic off- to on-peak spot price variability; variability in off- and on-peak prices and load levels are assumed to be perfectly correlated within each month. See Figures 2a and 2b for these prices and volatilities.
- Time frame shifted from calendar year to planning year (June-May) for 2009, 2010 and 2011; this represents the first periods that are not already covered and that could be supplied under a managed portfolio approach. Calendar years 2014-2016 added as extrapolations of current market term-structure of prices and volatility.
- Energy efficiency and demand response (DR) load reductions based on SEU projections and Delmarva's own DR program taken out of the RSCI load.
- Renewable energy requirements satisfied by RECs purchased at forecasted ICF prices, or by wind resources primarily located in western PJM, similar to offers recently solicited in Delmarva's Land Based Wind RFP.
- Intraday hourly patterns of load and LMPs modeled by imposing historical intraday spot patterns on future monthly average load and forward price "draws" (no stochastic intraday modeling)
- Gas-price forwards and volatilities added, from broker quotes; used to determine when gas-fired generation would be economically dispatched.
- Costs for RECs, ancillary services, capacity payments and revenues are added to Monte Carlo energy costs to capture total contract costs.

ICF Market Model – ICF maintains a proprietary power market simulation model that allows hourly projections of LMPs and corresponding plant usage and costs under economic dispatch subject to transmission constraints. It is being used to evaluate Delmarva's Land Based Wind Resource RFP responses under a variety of scenarios spanning possible evolutions of the PJM market. Long-run scenarios spanning various possibilities for transmission expansion, fuel price escalation, and CO_2 pricing have been evaluated. Brattle relies on these scenarios in its modeling in the following ways:

- Forecasted REC prices are used to satisfy renewable energy standards in strategies where wind resources are not obtained.
- Annual electricity price escalation rates from the ICF Base Case scenario are used to extrapolate market forward curves in years when they are no longer traded
- High and low scenarios for 2014 and 2016 are created by shifting the Base Case, market-extrapolated forward curve up or down to the same extent the ICF high and low cases shift relative to their Base Case.

Results for 2014-16 are presented from the perspective of a portfolio manager evaluating risks in January, 2013, assuming a specific ICF scenario is then prevailing (e.g., the high-carbon, high natural gas scenario). The portfolio manager would project the range of potential annual costs for 2014-16 (based on the same volatility function that applies in 2008) centered around each ICF scenario

Portfolio Composition

In developing the managed portfolio proposed herein by Delmarva, Brattle and Delmarva considered two benchmark portfolios that represent bracketing extremes of risk exposure: (1) an all-spot portfolio consisting solely of transactions entered in the PJM energy markets (plus capacity, ancillary services, and RECs as needed to satisfy RPS obligations) and (2) an all-fixed, single forward-price portfolio obtained by procuring all of the delivery year's requirements at once, and then balancing those amounts in the spot market for delivery volumes that are higher or lower in any hour than the level contract quantity. The former is the most risky, while the latter is the least. However, the latter is exposed to the most potential hindsight "regret" from the possibility that the forward purchases will have been made at a time that has a high cost relative to other times, as seen after the fact. The Managed Portfolio has been designed to have risk characteristics in between these two benchmarks. Delmarva's proposed portfolio balances these tradeoffs by consisting of:

- A one-year, base-load, all-hours component for 100 MW at the same fixed price for all months in the delivery year (50MW in the initial portfolio year). This component is priced at the average 12-month strip price of the standard wholesale PJM forward contract trading at the time of purchase. Figures 3 and 4 show the size of this component in relation to the Managed Portfolio load levels for RSCI customers in 2011-12. The first figure shows that the minimum RSCI hourly load is never below 100MW. The second reorders that load as a load duration curve, and shows that a 100MW block represents about 37% of the portfolio's RSCI energy requirements (net of DSM programs).
- Spot purchases for approximately 10% of each month's average on-peak energy needs, <u>not</u> pro-rata across each hour (i.e. not 10% of each hour). This spot component helps to reduce switching risks and costs.
- A "dollar cost averaging" (DCA) portion composed of purchases made in twelve monthly installments for the remaining energy needs of each future month, beginning approximately one year ahead of delivery schedule. Such purchases must occur in 50

MW blocks, because that is the standard contract size in PJM. Accordingly, some purchases are delayed until standard block size is feasible.

The average monthly on–peak RSCI loads, and the corresponding purchase volumes by type of contract, are shown in Figure 5. The purchasing matrix for on-peak requirements, describing when forward commitments are struck for each delivery month, is shown in Figure 6. (Off-peak purchasing consists exclusively of the 100MW annual block and spot purchases, so it does not require a matrix of planned procurement times.)

Figure 7 shows how the above portfolio lies between the extremes of buying all power at spot (most risky) or buying it all in advance at a fixed price (and balancing the difference between forward volumes and actual load shapes in the spot market). The latter has the least true risk but the most potential for regret. The slope of these S-shaped curves reflects their risk, with a steeper curve being less risky (less chance of a wide range of realized annual costs) and a wide, flat curve being more risky. (The mechanics behind how such curves are derived is explained in detail in the March 5, 2008 IRP Update previously filed by Delmarva).

The Base Case for the managed Delmarva portfolio includes no wind resources. The costs of RECs are added to the simulations to cover renewable resources equal to the annual requirements. Annual REC prices are projected in ICF's Base Case forecast to be in the $10-$20/MWh range, as seen in Figure 8.

Two alternative cases include wind. The first includes western PJM wind resources equal to 110MW in 2010 and 160MW in 2011 with additional amounts added in later years to achieve 110% of annual renewable energy requirements. These land-based wind resources are priced at terms consistent with the results of Delmarva's recent Land Based Wind Resource RFP. None of these resources have been offered under terms that include capacity credits, so they are modeled as only being a source of spot energy and RECs. The second wind scenario relies on using RECs initially, then obtaining renewable energy from BlueWater Wind from 2014 and beyond.

In either case, when the wind-generated sales revenues exceed the contract costs for the resource, Delmarva's total portfolio costs will be reduced. Risks may or may not be reduced, depending on the predictability and timing of the wind resource's output (as well as fixed costs). In the model, the pattern of wind speed is assumed to vary deterministically by hour of day, by month, and it is also assumed to vary randomly; both factors are estimated from historic patterns of wind variability, applied to a production function applicable to a typical wind turbine. Wind energy is sold at the hourly spot prices arising in the Monte Carlo simulations of the delivery periods of the Managed Portfolio.

Base Case Results in Planning Years 2009-2011

Figure 9 depicts the expected portfolio distributions of average annual cost per MWh in each of the planning years 2009-2011. (This and all subsequent charts and cost calculations exclude the costs from pre-portfolio commitments of FRS contracts that expire gradually over that time frame, and they exclude any costs of implementing the SEU and Delmarva conservation and demand response programs. That is, these curves depict just the range of foreseeable costs of the actively managed portfolio's wholesale contracts for power, plus capacity, ancillary services, and RECs.) This chart shows that the curves shift outwards by a few $/MWh each year, but their average cost is generally around $100/MWh. The curves also become somewhat riskier (wider) in the later years. This is because the curves are drawn from the perspective of how much future cost uncertainty there is in 2008 for each of those future years. That cumulative uncertainty grows over time.

Effects of Land-Based Wind

Adding wind to the Managed Portfolio has two effects: First, it shifts the average cost curve out to slightly higher levels (towards the right), because on average the Land-Based wind resources have been offered at a price that is above the wholesale price for forward power now prevailing in PJM. Combining this with the fact that wind energy is often produced at times when LMPs are not near their maximum levels means that the offered contracts do not produce net savings for Delmarva customers, even with the REC savings they produce. Figure 10 shows the average wind generation foreseen for the western land-based wind resources (as well as the BlueWater facility), by hour for a typical week in February in relation to RSCI load levels. Note that both the land and off-shore wind facilities tend to produce more power at night, when loads are low, than in mid-afternoons when loads (and LMPs) are high. Thus, wind power tends to be most available when it is little needed. This is also true on a seasonal basis – wind output in the summer months is typically lower than in the fall and spring.

As a result, the costs of wind are high relative to its benefits, as seen in Figure 11, which shows the distribution of costs and revenues per MWh foreseeable from the land-based resources in 2010. The green vertical line on the left represents their cost to Delmarva for energy plus RECs; the blue S-shaped curve of revenues depicts the value of spot energy sold into PJM-West, plus the ICF forecast of REC values. The red S-curve is the net value, which is negative for over 90% of the draws. For comparison, the S-curve for supplying the RSCI load at all spot prices is shown at the far right. It has a higher average cost, because the wind output is more concentrated in off peak hours. This makes it less valuable, but also a bit less risky (since off-peak spot prices are not as variable as on-peak prices).

Longer Term Assets

Because of rising LMPs and capacity prices (as well as uncertainty over the completion of announced transmission projects), it is worthwhile to evaluate whether a contract tied to a gas-fired generation plant could reduce the costs or risks of a Managed Portfolio. This prospect has been evaluated by considering the following two scenarios: 1) buying a 100MW CT or 2) entering a 10-year contract for the output of a CC, simulated at the levelized nominal carrying charges for a new CC and at the average 10-year forward price of natural gas delivered to eastern PJM in on-peak hours. The stand-alone economics of the CT are shown in Figure 12. It compares the annual fixed costs of the peaker to the revenues foreseeable in the Delmarva zone from its spot energy sales and capacity. The net revenue curve is in the middle, and it is substantially positive, indicating that this peaker will reduce costs in all but a small percentage of foreseeable scenarios. A CC-based contract involves somewhat larger carrying charges, ut it also offers more hours of potential energy benefits. Like the CT, it has been evaluated in the Managed Portfolio in conjunction with the land-based wind resources, with the results described below.

Comparison of Strategies in the Near Term

Figure 13 is a portfolio cost and risk comparison across all of the alternatives considered for the near term. (BWW is not considered near term because it does not come on-line until 2014). There is only about a $6/MWh, or about 6%, spread across the alternatives at the median scenario, so they are all fairly similar. Their risk shapes are also substantially the same, because none of them includes a great deal of any resource not priced at, or similar to, the wholesale prices underlying the Managed Portfolio. The lowest cost alternative is the Managed Portfolio with RECs, while the lowest risk alternative is the Managed Portfolio plus land-based wind with the CT. The CC with land-based wind is less attractive than including just the land-based wind in the portfolio, or than the land-based wind plus the CT, by about $4/MWh on average.

Long Term Performance -- BlueWater

Under base case conditions, derived by extrapolating the current market forward curves for gas and electricity at the annual escalation rates in the ICF forecasts for 2014 and beyond, the BlueWater Wind resources are very unlikely to have net benefits for Delmarva's customers. Its main problem is that the proposed charges to Delmarva are extremely high in comparison to market prices and the cost of other alternative conventional and renewable resources. At least over the first few years of its operation, its contract charges are far above market prices for the combined value of all of its outputs (energy, capacity, and RECs).[2] Figure 14 depicts the foreseeable distributions of costs vs. revenues in 2016 for both the wind portion alone and the CTs that have been proposed as backup by Conectiv. Combining the proposed charges for capacity, energy, and RECs, Delmarva would be paying about $155/MWh for the rights to BWW. Unfortunately, the market value of all of its outputs is more likely to be in the $65-125 range, resulting in a huge expected loss of around $60/MWh. The result is that the blue S-curve for net revenues from BWW lies far to the left of the zero-benefit point on the x-axis.

Adding in the backup peaking units does not help. The basic terms of this offer are for Delmarva to pay for all of the fixed costs of two LMS-100 CTs, in order to obtain their capacity benefit (195MW) and rights to their energy when it is economic, to the extent that BWW is not producing its contractual maximum output of 300MWh per hour. Thus, Delmarva is not entitled to all of the energy value of the facility, only to the value that occurs when the wind is not blowing hard enough to yield 300MW at BWW.

[2] No ancillary service revenues were assumed to be earned by the wind resources. Likewise, no incremental ancillary service costs, e.g. from more difficult load following or more costly unit commitment of other, conventional resources, are assumed, even though some studies have suggested that large wind resources may slightly increase system operational costs.

The overall impact of taking the BWW offer, with or without the Conectiv Energy CTs, would be to increase the portfolio costs by about 30%, as seen in Figure 15.[3]

Comparison of Long Run Alternatives

Figure 15 also includes the results for continued reliance on the Managed Portfolio with various combinations of a continuation and extension of the land-based wind resources and a peaking unit. As in 2009-11, the distribution is tight and similar in shape for all the alternatives. Also as before, the Managed Portfolio with RECs is the cheapest, while the lowest risk and only slightly higher costs occur with the Peaker and the land-based wind resources. The land-based wind plus long-term contract priced as a CC is more attractive than it was in the near term, but still less so than the other alternatives (except BWW).

Scenarios with Alternative Gas and CO2 Prices

ICF has developed alternative long-run scenarios that assume considerably higher and lower natural gas prices and CO2 prices could prevail in 2014-16 and beyond. These are annual costs, and it is assumed that the volatility of market prices in those scenarios is the same as it was in the base case. As a result, the annual levels for CO2 and RECs will not affect the shapes of the annual average cost distributions, just their locations. That is, scenarios with higher CO2 prices or lower REC values will cause a uniform lateral shift in the base case distribution for a given strategy. This is seen in Figure 16, which shows how the costs of the Managed Portfolio with RECs move up and down with higher or lower annual environmental costs. The shift is approximately \$9/MWh in either direction.

Changes in the value of RECs or CO2 will affect the other portfolio strategies in the same fashion as the Managed Portfolio with RECs, i.e., shifting their respective base case distributions uniformly to the left or right. However, changes in CO2 or REC prices will <u>not</u> affect each strategy to the same extent. The BWW strategy is the least sensitive to CO2 prices (since it offsets the most of these, via selling its output at spot in which the prices for CO2 are embedded) and it is the most sensitive to variation in REC prices (since it generates the most RECs). The no-wind, Base Case strategy will be most sensitive to CO2 prices. The resulting sizes of the shifts are shown in Figure 17, which compares the expected value annual costs in 2016 across all scenarios for each of portfolio strategies. Note that the range of expected costs is lowest for the BWW strategy, but it is always significantly more expensive than any other strategy, in any other scenario.

Potential Customer Migration Risk

If Delmarva enters long-term commitments to wind contracts or utility-owned generation, there is an increased risk that its portfolio costs will eventually diverge from prevailing market prices

[3] The distributions and cost tables for 2014-2016 describe calendar years, not PJM planning years.

and customer migration will occur. This can dramatically raise portfolio costs and/or impose unfair reallocation of costs on non-migrating customers. As explained more fully in Delmarva's May 15 IRP update, the Company is proposing to mitigate this customer migration risk in the following way: First, all costs associated with long-term contracts for wind-resources will be recovered through a non-bypassable charge. Second, if the Commission finds that construction of a utility-owned generation asset is in the public interest, then the cost of this asset should also be included in a non-bypassable charge. Finally, the Company has proposed a 5% "trigger mechanism" that is activated to create a non-bypassable charge to protect SOS customers from migration risk.

Conclusions

Based on analysis to date, it appears that a Managed Portfolio comprised of a mixture of fixed annual-price base-load contracts, dollar-cost averaging monthly forwards, and a modest amount of spot power would strike an appropriate balance between risk and regret. The exact proportions do not matter greatly for current purposes of understanding how additional resources might complement such a portfolio (though they should be explored more fully in planned workshops, to strike an appropriate balance between *ex ante* risk and *ex post* regret). Both land-based wind and local gas peaking resources are attractive additions to the Managed Portfolio, having small effects on total costs and modest risk-reduction benefits, while providing some additional reliability benefits and protection against future REC and CO2 price uncertainty.

In contrast, the proposed BWW facility and its backup peakers are very unattractive, with pricing terms that are dramatically above the cost of better alternatives. It is not well sized or timed to satisfy the needs of this portfolio.

Table 1
Long-Term Portfolio Procurement with Renewables Strategies

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Base Case - Managed Portfolio (with RECs)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Scenario I - Managed Portfolio plus Land-Based Wind	N/A	$100.65	$105.99	$106.12	$107.02	$107.76	N/A	$29.41	$31.40	$19.83	$24.62	$27.29
Scenario IV - Managed Portfolio plus Bluewater Wind (BWW)	N/A	N/A	N/A	$134.76	$136.31	$137.77	N/A	N/A	N/A	$13.04	$17.05	$19.28
Scenario V - Managed Portfolio plus BWW Hybrid	N/A	N/A	N/A	$136.04	$136.33	$137.50	N/A	N/A	N/A	$13.16	$15.84	$17.61

Table 2
Long-Term Portfolio Hedging Options

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Base Case - Managed Portfolio (with RECs)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Scenario II - Managed Portfolio plus Land Wind w/ Regulated Asset (CT)	N/A	$99.45	$104.55	$106.95	$107.56	$108.14	N/A	$22.36	$24.23	$16.87	$21.92	$24.23
Scenario III - Managed Portfolio plus Land Wind w/ Longer Term Contracts (CC)	N/A	$103.73	$108.68	$107.87	$108.46	$109.02	N/A	$29.43	$31.36	$19.83	$24.62	$27.29

Table 3
Portfolio Risk-Positioning Comparison

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Strategy A: 100% Fixed Portfolio	$98.14	$97.66	$102.65	$106.70	$107.96	$108.90	$2.59	$2.83	$2.19	$2.64	$2.80	$2.82
Strategy B: Managed Portfolio (Base Case)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Strategy C: 100% Open Portfolio	$98.13	$97.70	$102.71	$106.50	$107.82	$108.70	$68.16	$71.31	$70.63	$62.25	$68.22	$72.04

Note: All tables should include energy, capacity, rec, congestion, and ancillary costs.

Table 1
Long-Term Portfolio Procurement with Renewables Strategies

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Base Case - Managed Portfolio (with RECs)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Scenario I - Managed Portfolio plus Land-Based Wind	N/A	$100.65	$105.99	$106.12	$107.02	$107.76	N/A	$29.41	$31.40	$19.83	$24.62	$27.29
Scenario IV - Managed Portfolio plus Bluewater Wind (BWW)	N/A	N/A	N/A	$134.76	$136.31	$137.77	N/A	N/A	N/A	$13.04	$17.05	$19.28
Scenario V - Managed Portfolio plus BWW Hybrid	N/A	N/A	N/A	$136.04	$136.33	$137.50	N/A	N/A	N/A	$13.16	$15.84	$17.61

Table 2
Long-Term Portfolio Hedging Options

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Base Case - Managed Portfolio (with RECs)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Scenario II - Managed Portfolio plus Land Wind w/ Regulated Asset (CT)	N/A	$99.45	$104.55	$106.95	$107.56	$108.14	N/A	$22.36	$24.23	$16.87	$21.92	$24.23
Scenario III - Managed Portfolio plus Land Wind w/ Longer Term Contracts (CC)	N/A	$103.73	$108.68	$107.87	$108.46	$109.02	N/A	$29.43	$31.36	$19.83	$24.62	$27.29

Table 3
Portfolio Risk-Positioning Comparison

Settlement Period:	Total Average Costs ($/MWh)						Price Spread - (90th - 10th Percentile) ($/MWh)					
Settlement Period: (June-May)	2009/10	2010/11	2011/12	2014	2015	2016	2009/10	2010/11	2011/12	2014	2015	2016
Strategy A: 100% Fixed Portfolio	$98.14	$97.66	$102.65	$106.70	$107.96	$108.90	$2.59	$2.83	$2.19	$2.64	$2.80	$2.82
Strategy B: Managed Portfolio (Base Case)	$97.62	$99.61	$104.49	$105.73	$106.63	$106.99	$26.81	$32.04	$34.88	$23.43	$28.91	$32.79
Strategy C: 100% Open Portfolio	$98.13	$97.70	$102.71	$106.50	$107.82	$108.70	$68.16	$71.31	$70.63	$62.25	$68.22	$72.04

Note: All tables should include energy, capacity, rec, congestion, and ancillary costs.

Table 4
Long-Term Portfolio Procurement with Renewables Strategies

Settlement Period: 2016	90th Percentile	10th Percentile
Base Case - Managed Portfolio (with RECs)	$121.59	$88.80
Scenario I - Managed Portfolio plus Land-Based Wind	$119.36	$92.07
Scenario IV - Managed Portfolio plus Bluewater Wind (BWW)	$144.58	$125.30
Scenario V - Managed Portfolio plus BWW Hybrid	$143.32	$125.71

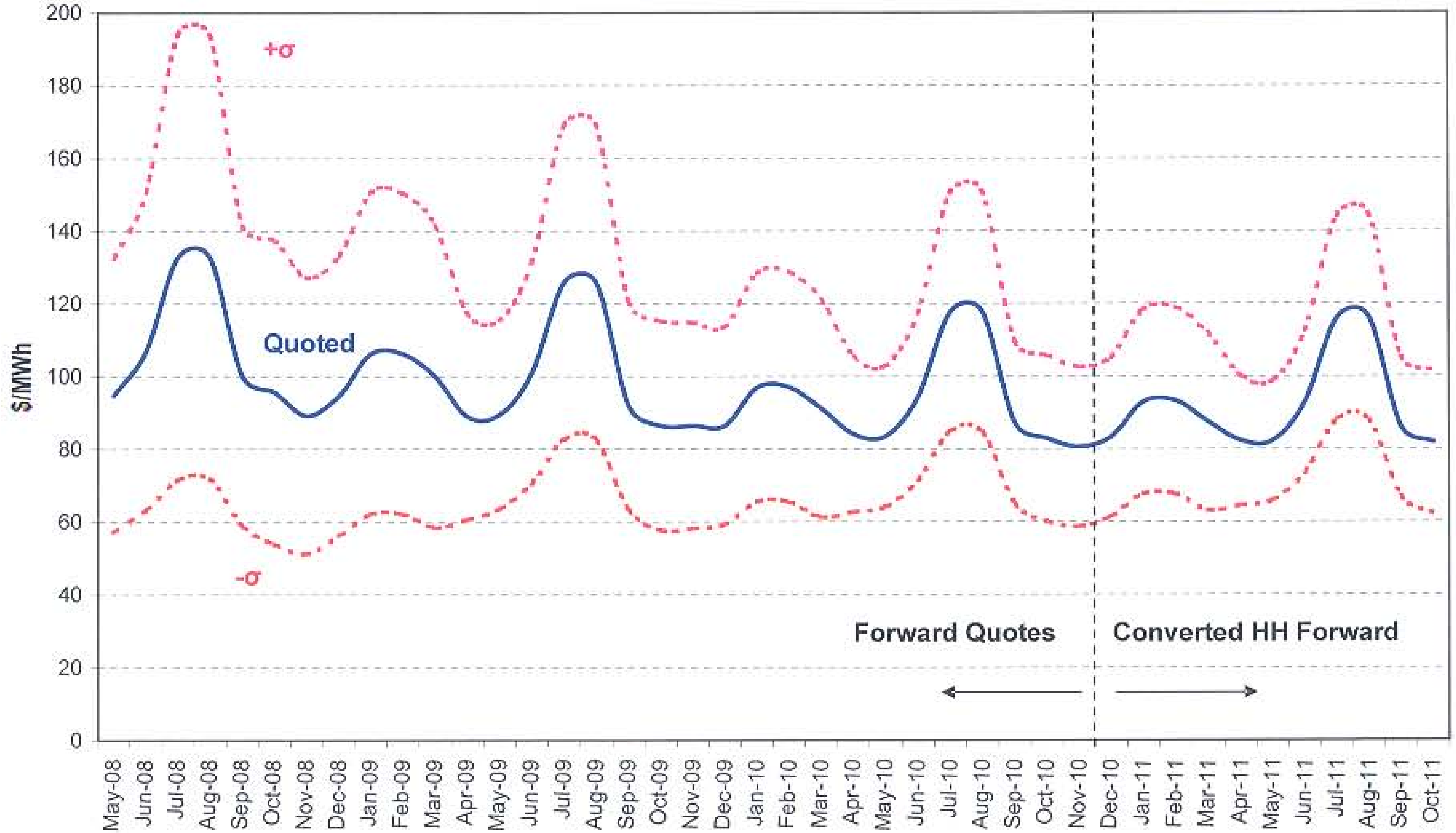
Table 5
Long-Term Portfolio Hedging Options

Settlement Period: 2016	90th Percentile	10th Percentile
Base Case - Managed Portfolio (with RECs)	$121.59	$88.80
Scenario II - Managed Portfolio plus Land Wind w/ Regulated Asset (CT)	$117.92	$93.69
Scenario III - Managed Portfolio plus Land Wind w/ Longer Term Contracts (CC)	$120.62	$93.33

Table 6
Portfolio Risk Positioning Comparison

Settlement Period: 2016	90th Percentile	10th Percentile
Strategy A: 100% Fixed Portfolio	$107.34	$104.52
Strategy B: Managed Portfolio (Base Case)	$121.59	$88.80
Strategy C: 100% Open Portfolio	$144.86	$72.82

Figure 1a: Estimated DPL Forward Peak Price with Uncertainty as of April 9, 2008



Note: DPL forward price is obtained from PJM West forward price by adding congestion from west to east hub and a $1 physical premium. It is projected forward after January 2010 by converting Henry Hub gas forward price at an estimated average heat rate.

Figure 1b: Volatility Term Structure Fit as of April 9, 2008

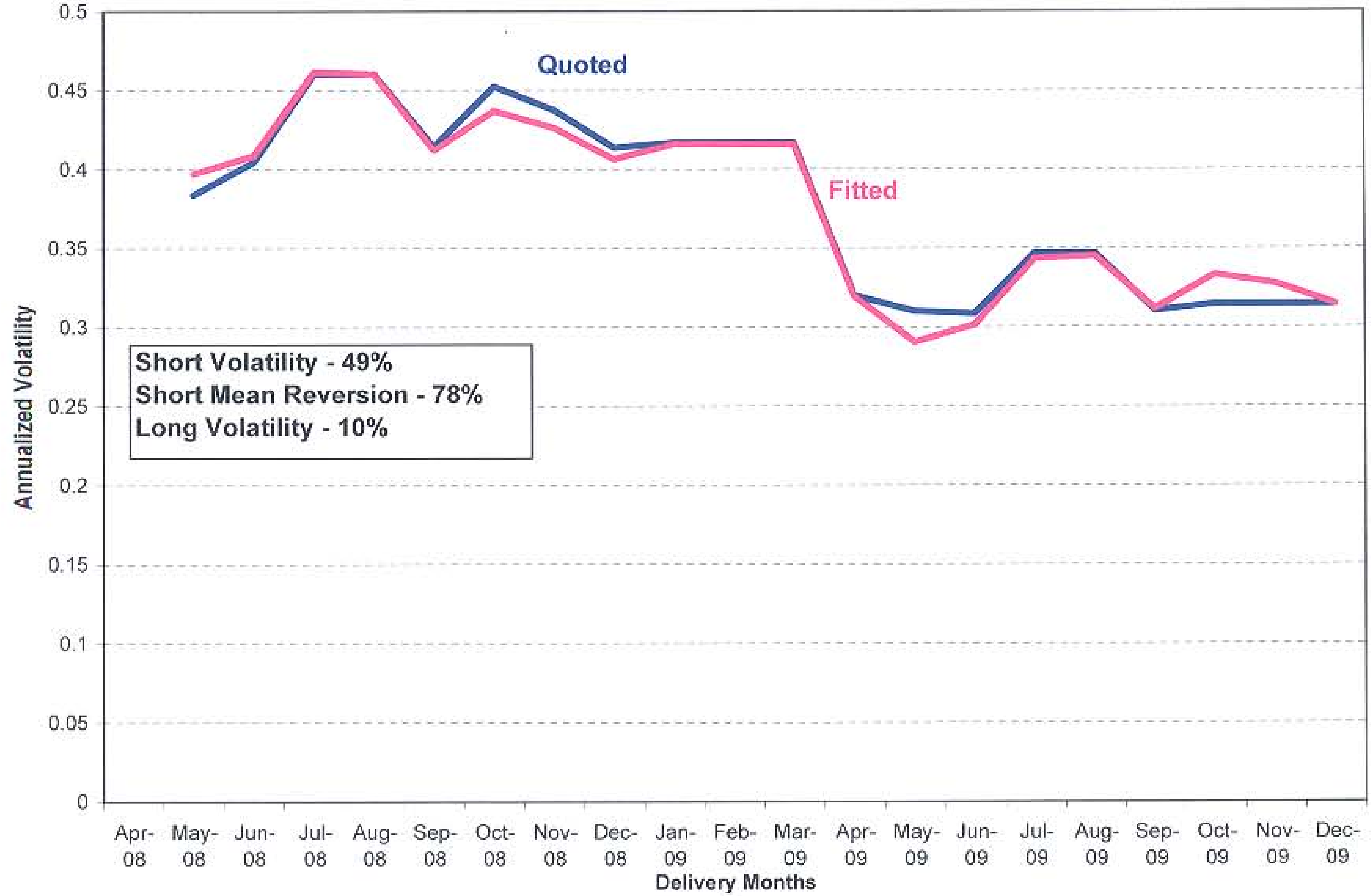
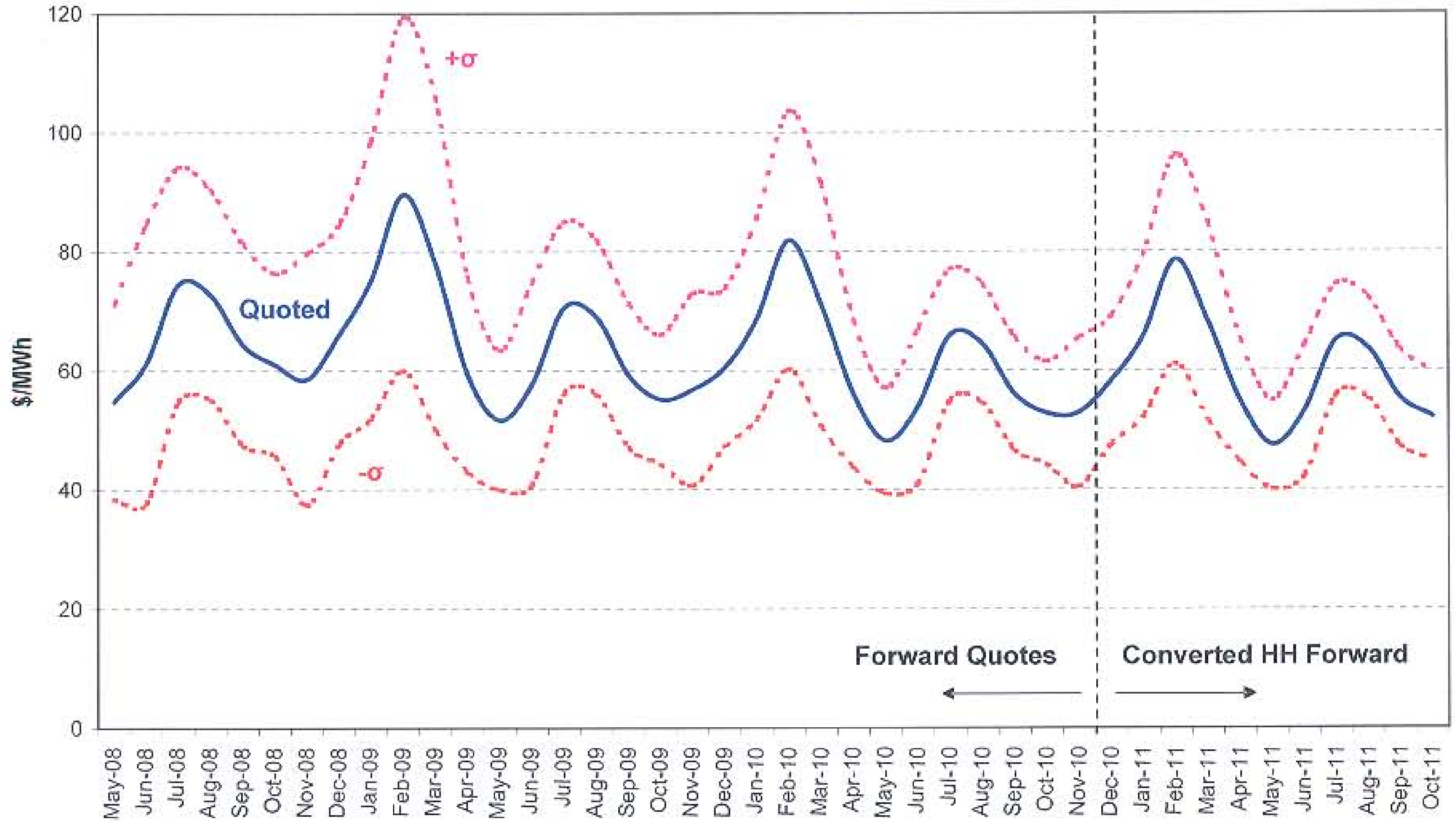


Figure 2a: Estimated DPL Off-Peak Forward Price with Uncertainty as of April 9, 2008



Note: DPL off-peak forward price is obtained from estimated DPL peak forward price by scaling down by peak-off-peak ratio estimated from DPL LMP prices.

Figure 2b: Off-Peak Volatility Term Structure Fit as of April 9, 2008

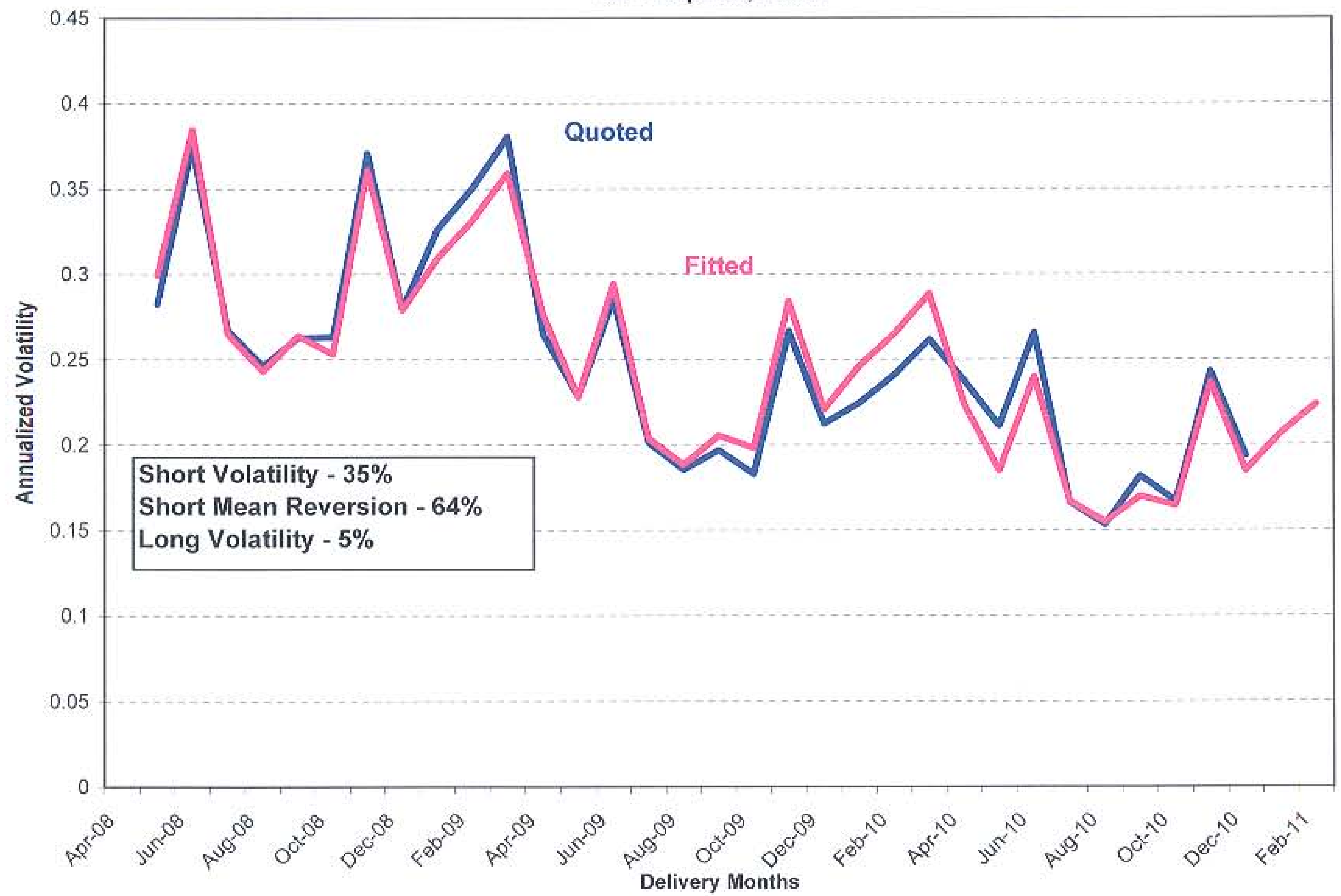
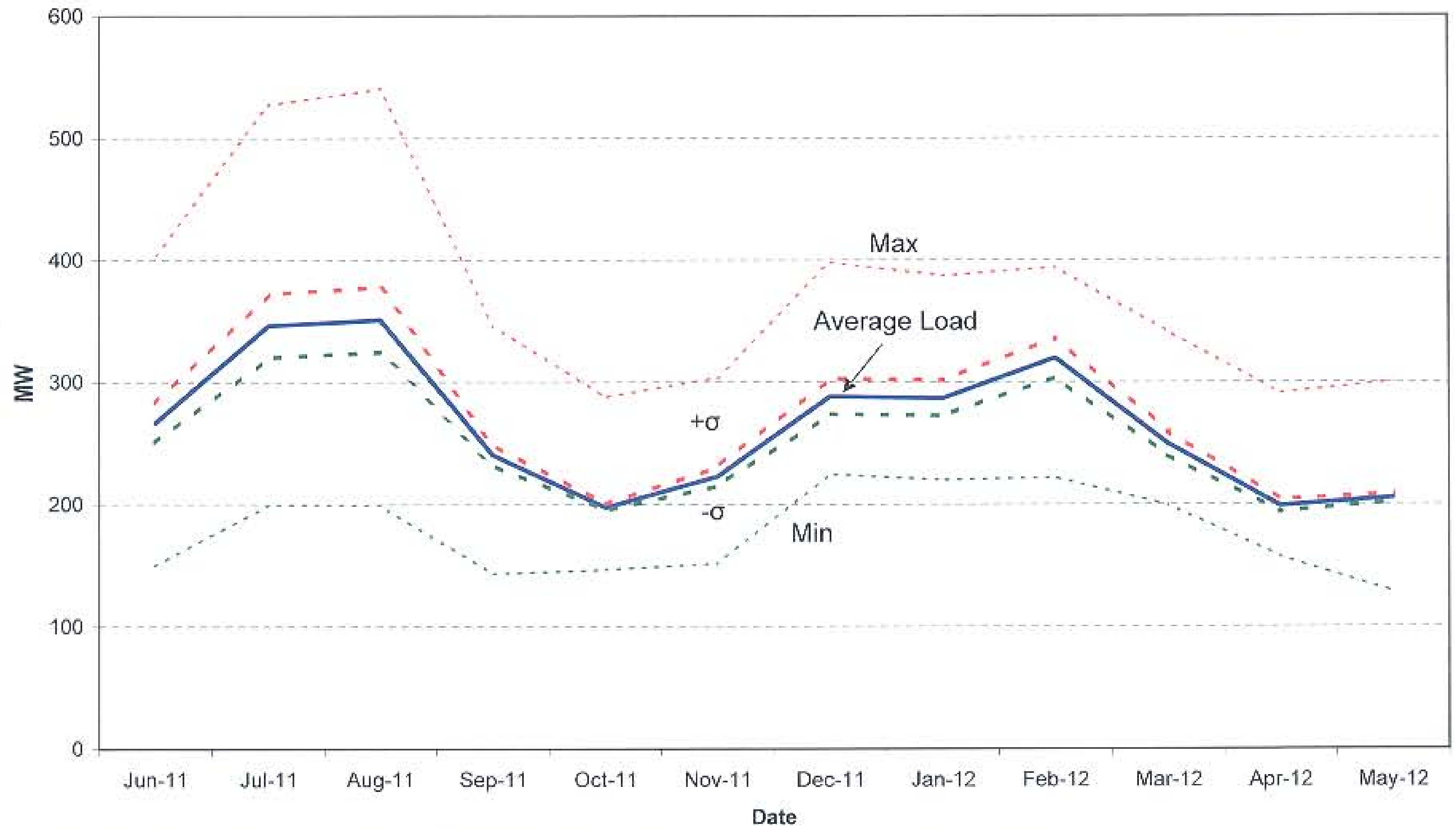
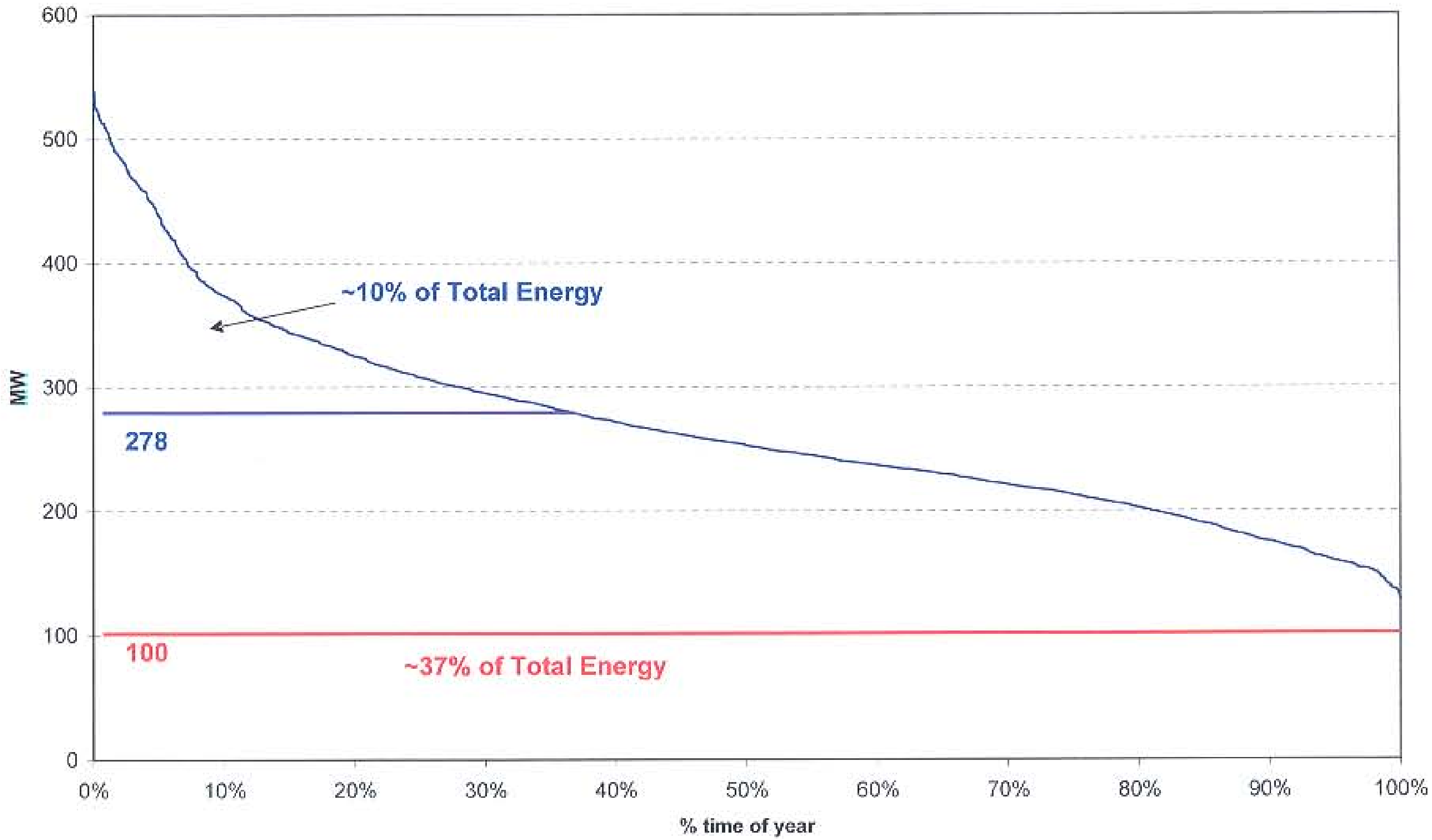


Figure 3: Average, Min and Max DPL Hourly Managed Portfolio Load for Residential and Small Commercial Customers



Note: Based on intraday load pattern constructed using intraday pattern for a representative week every month.

Figure 4: RSCI Managed Portfolio Load Duration Curve: 6/11-5/12



Note: Based on intraday load pattern constructed using intraday pattern for a representative week every month.

Figure 5: Portfolio layers shaped to match on-peak seasonal load (June 2011 to May 2012)

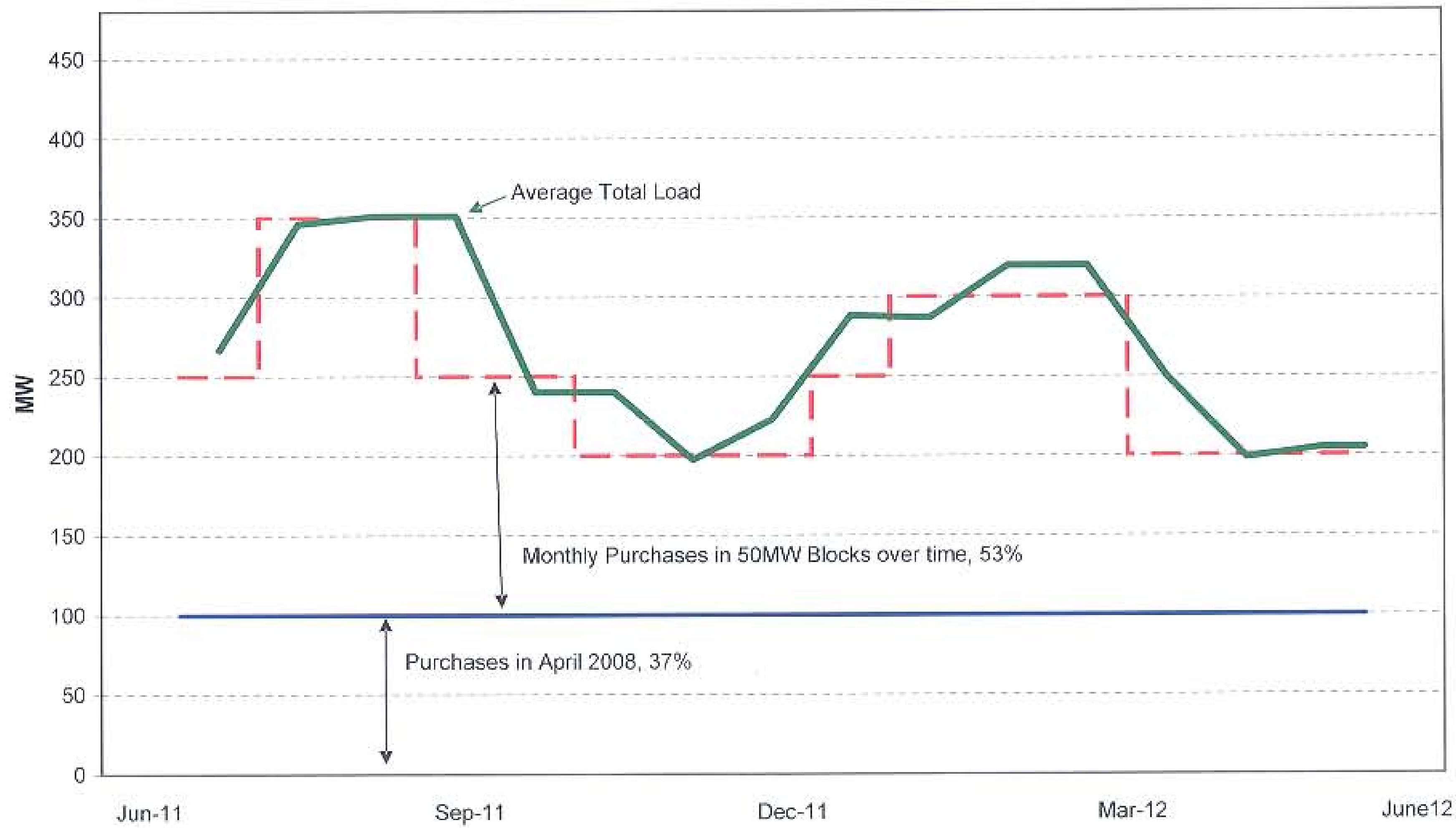


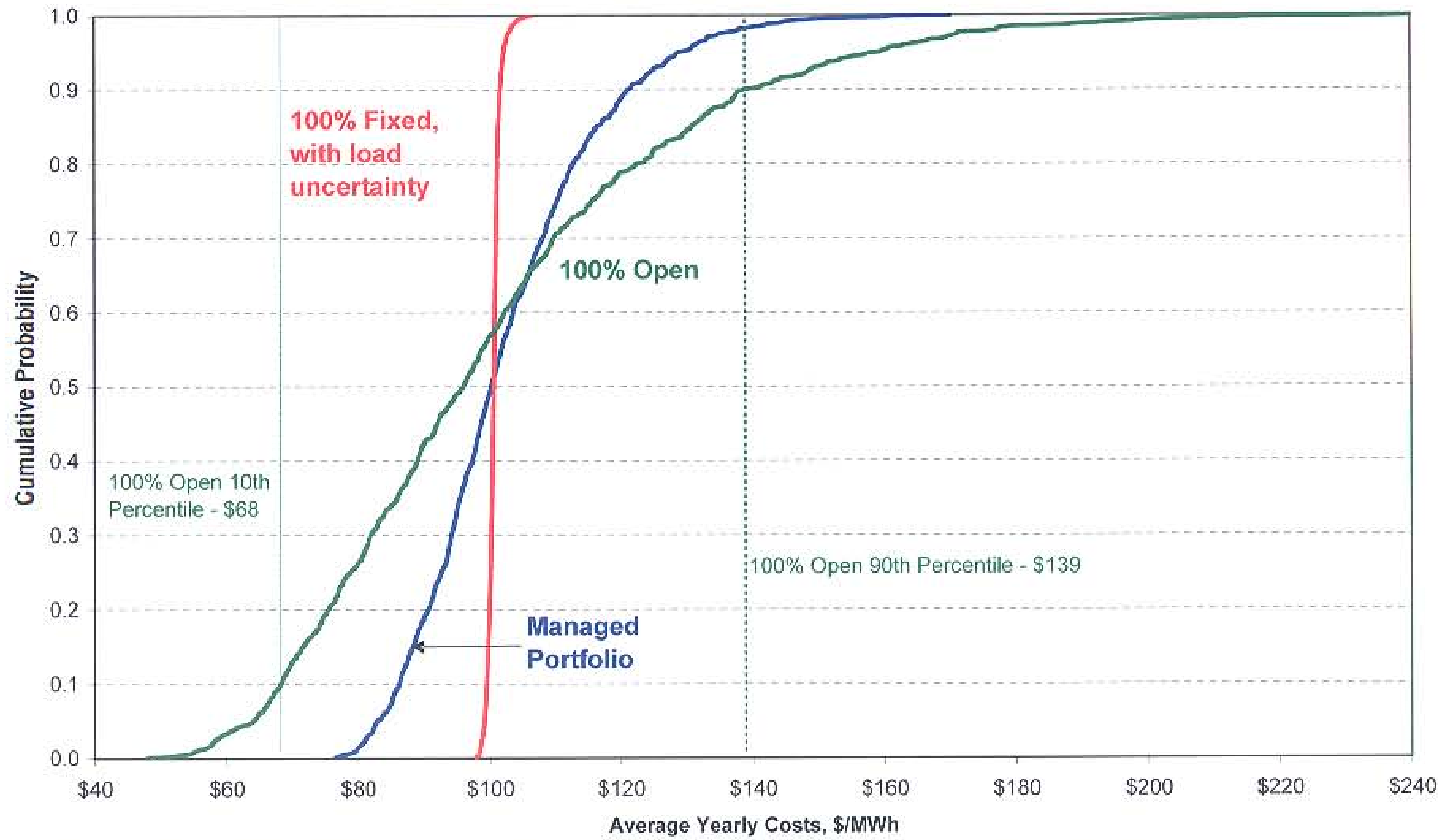
Figure 6: On Peak Procurement Schedule

	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Total	Percent
Monthly 50MW Blocks	17600	18400	16800	16800	17600	16000	17600	16000	16000	18400	17600	16000	17600	16800	17600	16800	16800	16800	18400	16800	16000	18400	16800	16800		
Number of Installments	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12		
Purchase Dates																										
Fixed Upfront Purchases	17600	18400	16800	16800	17600	16000	17600	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	32000	664,800	35.17%
5/1/08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
6/1/08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
7/1/08	-	-	-	-	-	-	-	16,000	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
8/1/08	-	18,400	16,800	-	-	-	-	-	-	18,400	-	16,000	-	-	-	-	-	-	-	-	-	-	-	-		
9/1/08	-	-	-	-	-	-	17,600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
10/1/08	17,600	-	-	16,800	-	-	-	-	-	-	17,600	-	-	-	-	-	-	-	-	-	-	-	-	-		
11/1/08	-	-	-	-	-	16,000	-	16,000	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
12/1/08	-	-	16,800	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
1/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
2/1/09	-	18,400	-	-	17,600	-	-	16,000	16,000	18,400	-	16,000	-	-	-	-	-	-	-	-	-	-	-	-		
3/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
4/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
5/1/09	-	-	16,800	-	-	-	17,600	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
6/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
7/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	17,600	-	-	-	-	16,800	16,000	-	-	-		
8/1/09	-	-	-	-	-	-	-	-	-	-	-	-	17,600	-	-	16,800	-	16,800	18,400	-	-	18,400	-	16,800		
9/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	17,600	-	16,800	-	-	-	-	-	16,800	-		
10/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	16,000	-	-	-		
11/1/09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
12/1/09	-	-	-	-	-	-	-	-	-	-	-	-	17,600	16,800	17,600	-	-	-	18,400	-	-	-	-	-		
1/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	-	-	-	-	16,000	18,400	-	16,800		
2/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	17,600	-	-	16,800	-	16,800	-	-	-	-		
3/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
4/1/10	-	-	-	-	-	-	-	-	-	-	-	-	17,600	-	-	-	16,800	-	18,400	-	-	-	-	-		
5/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	16,800	17,600	16,800	-	-	-	16,800	16,000	-	16,800	-		
6/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
7/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
8/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
9/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
10/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
11/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
12/1/10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
1/1/11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
2/1/11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
3/1/11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
4/1/11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
5/1/11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Total DCA Purchases	17,600	36,800	50,400	16,800	17,600	16,000	35,200	64,000	48,000	36,800	17,600	32,000	52,800	84,000	88,000	50,400	33,600	33,600	55,200	67,200	64,000	36,800	33,600	33,600	1,021,600	54.05%
Spot Purchases	22,829	7,624	(383)	8,432	(1,334)	6,258	(3,819)	2,815	15,685	11,554	11,327	9,756	8,455	8,619	13,041	386	894	3,665	6,998	4,232	6,763	16,864	1,595	11,234	168,449	8.91%
Total Managed Portfolio Volume	58,029	62,824	66,817	42,032	33,866	38,258	48,981	98,815	95,685	85,114	64,727	73,756	86,455	126,219	131,241	84,386	66,846	70,868	94,998	105,032	102,763	90,664	64,795	78,434	1,890,054	

50 MW Blocks

100 MW Blocks

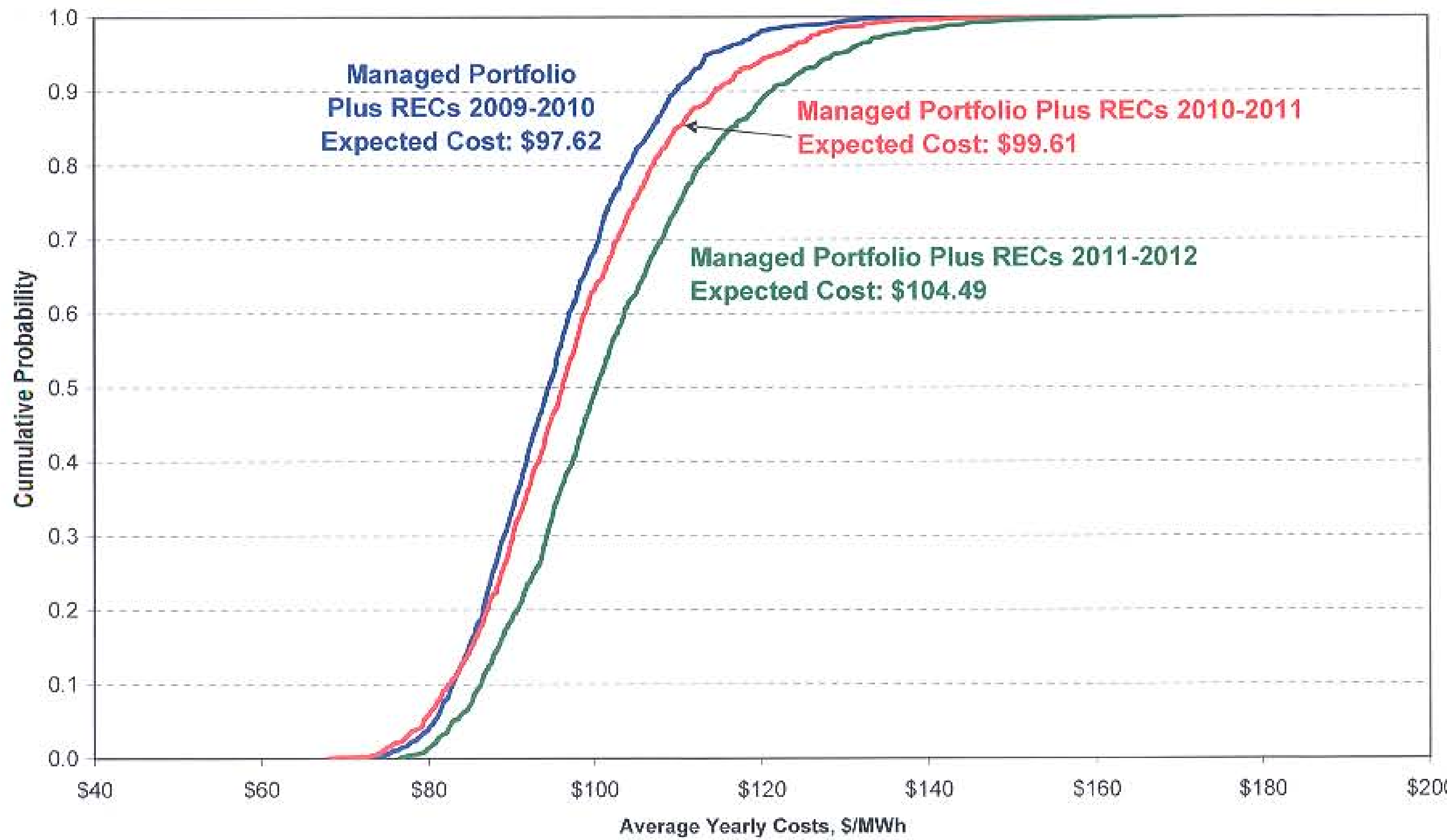
Figure 7: Comparative Risks of Different Procurement Strategies
Expected Costs in April 2008 for June 2011-May 2012 Energy Requirements



All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%.

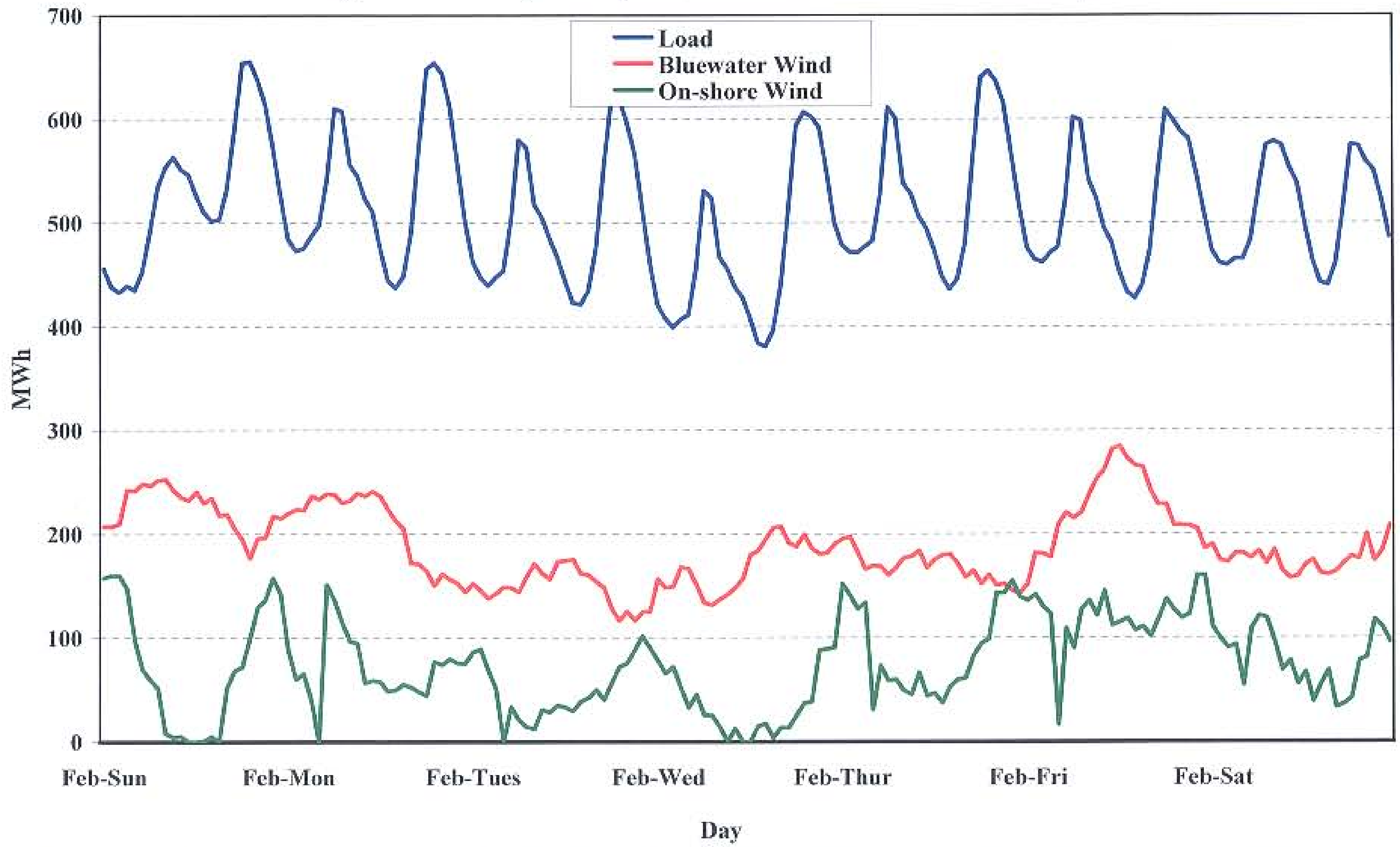
Figure 8: Carbon and RECs Price Forecasts

Figure 9: Comparative Risks of Managed Portfolio Plus RECs Expected Costs in April 2008 for 2009-2010, 2010-2011, and 2011-2012



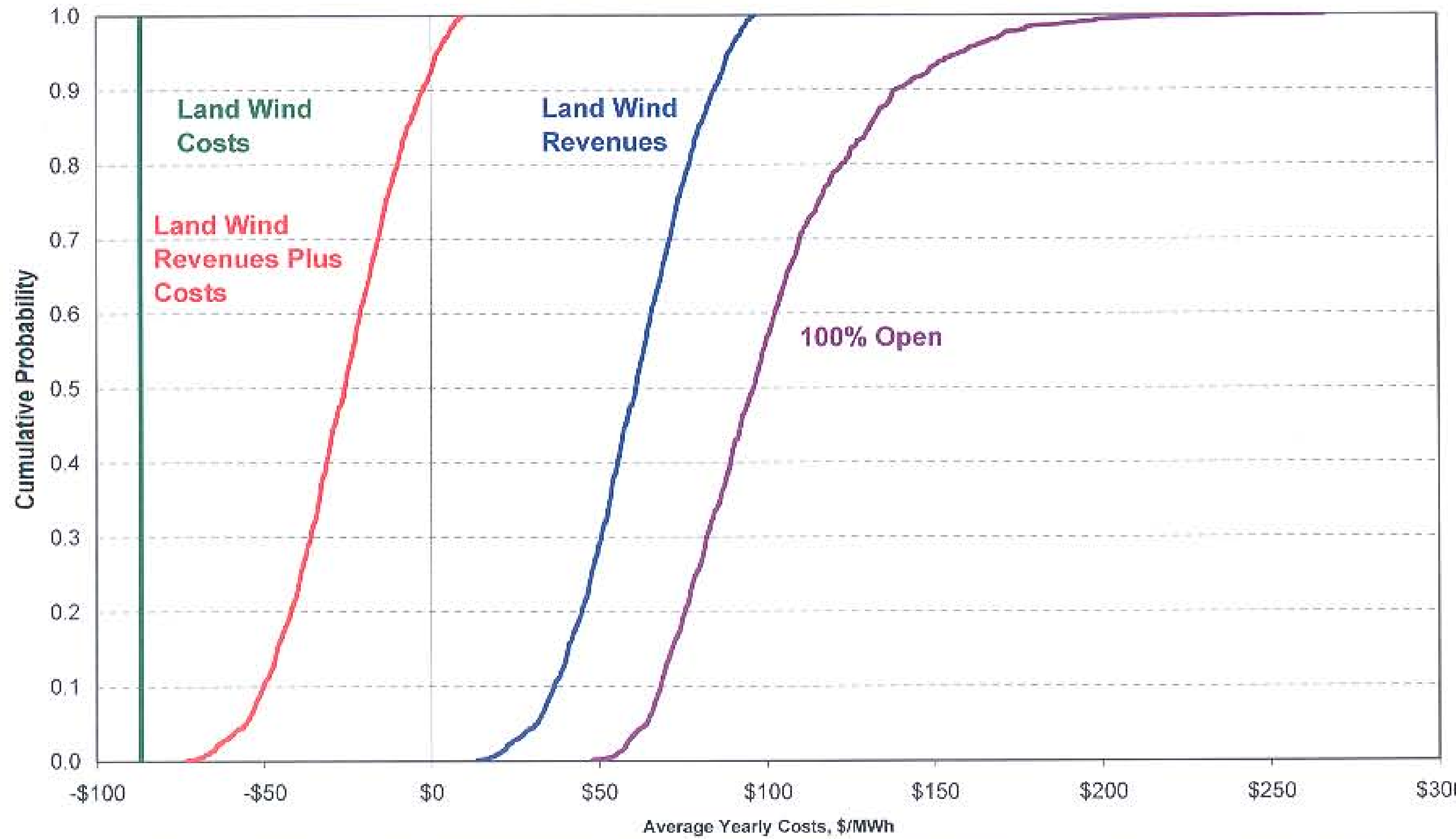
All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%.

Figure 10: Average Hourly Load and Wind Generation -- February



Note: Based on load data from August 2006 through 2007 and wind speed data from 2003 through 2007. Bluewater wind generation 450 MW of capacity capped at 300MW of output. On-shore wind assumes 160 MW of capacity.

Figure 11: Land Based Wind Revenues and Costs Expected as of April 2008 for June 2011-May 2012



All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%. Green Wind revenues at PJM West spot. Green Wind costs are for energy and RECs at flat commodity price.

Figure 12: Peaker Revenues and Costs
Expected as of April 2008 for June 2011-May 2012

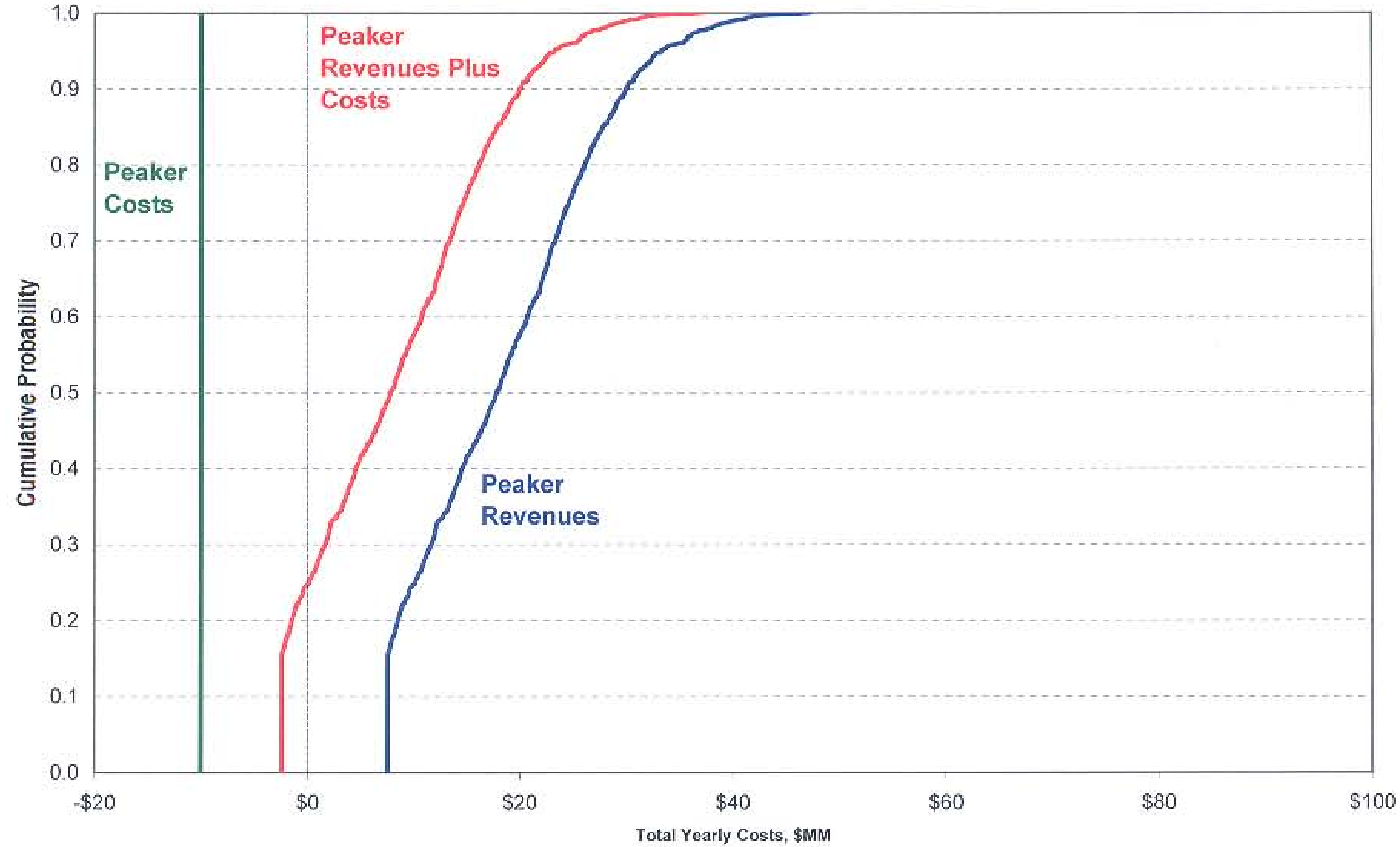
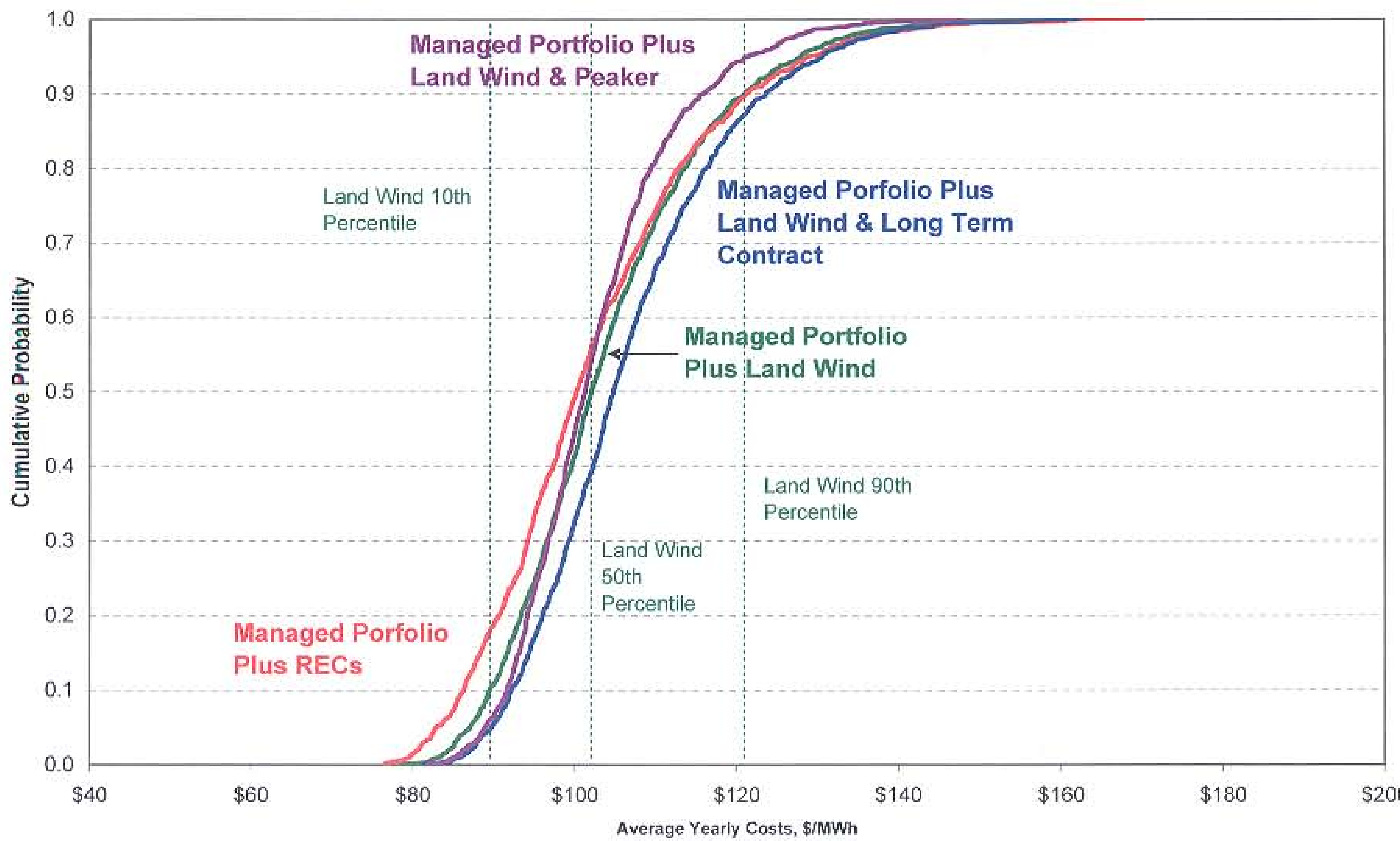
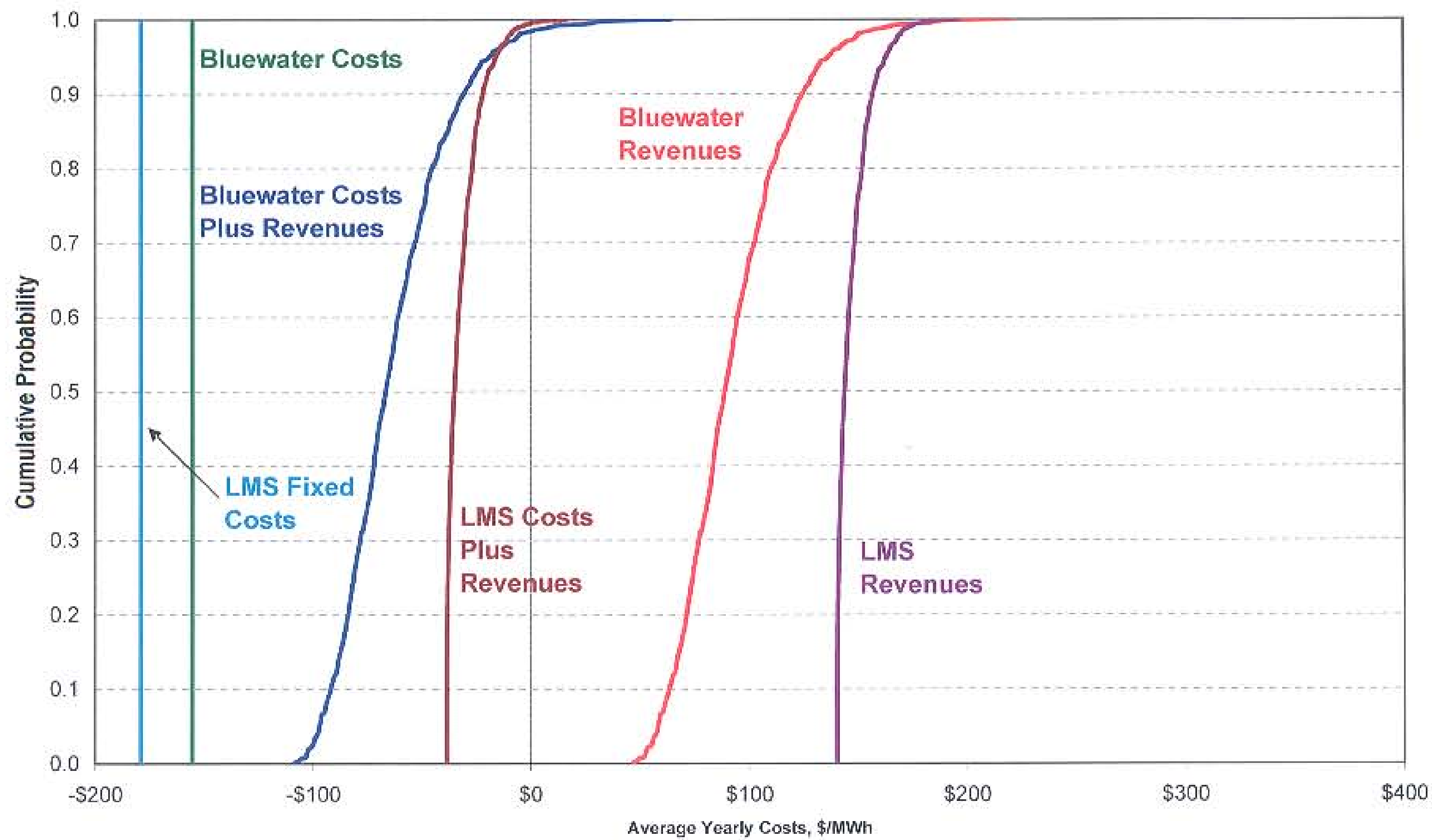


Figure 13: Comparative Risks of Managed Portfolio Plus RECs, Land Wind and Peaker Expected Costs in April 2008 for 2011-2012



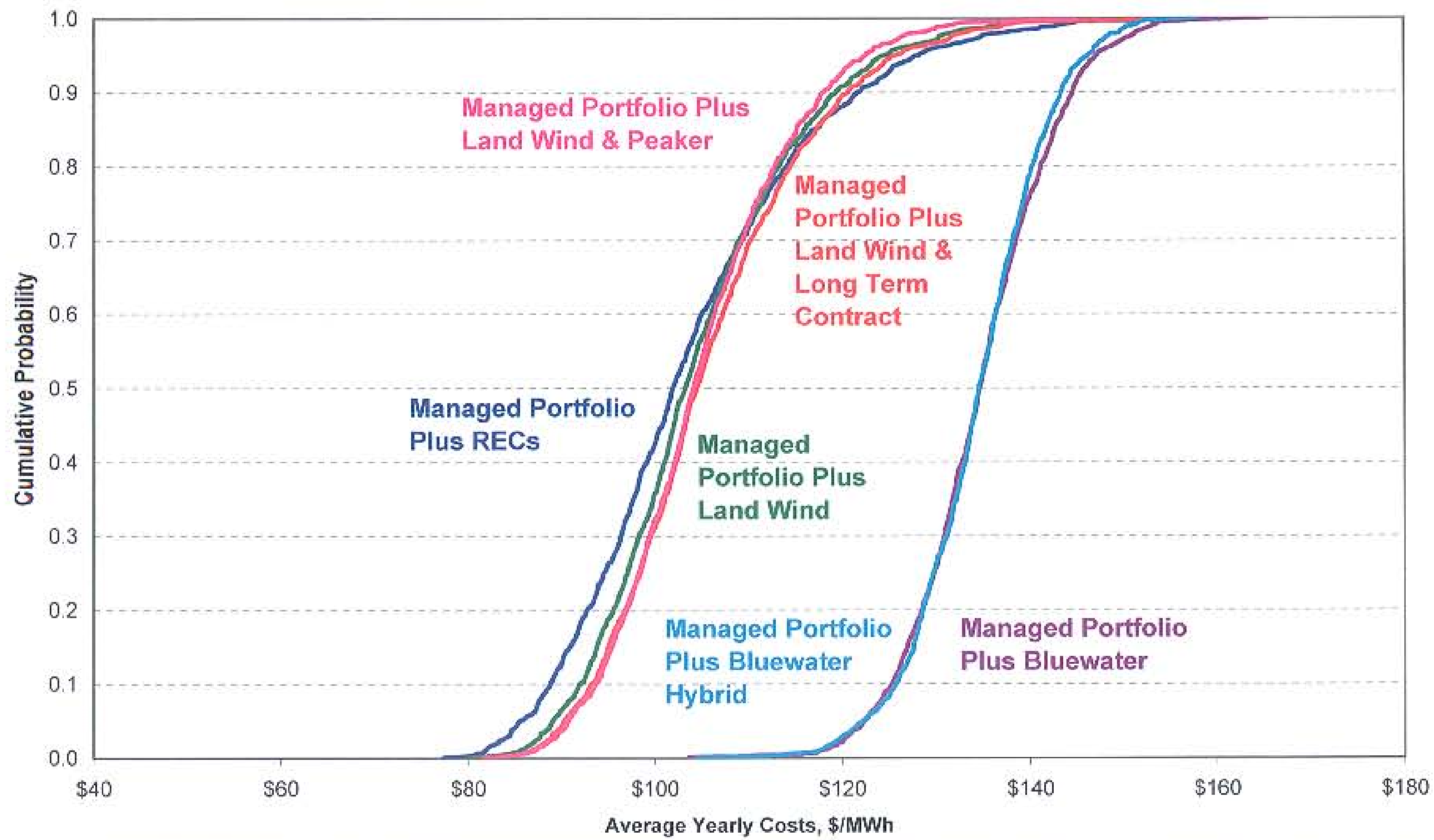
All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%.

Figure 14: Expected Bluewater Costs and Revenues for 2016



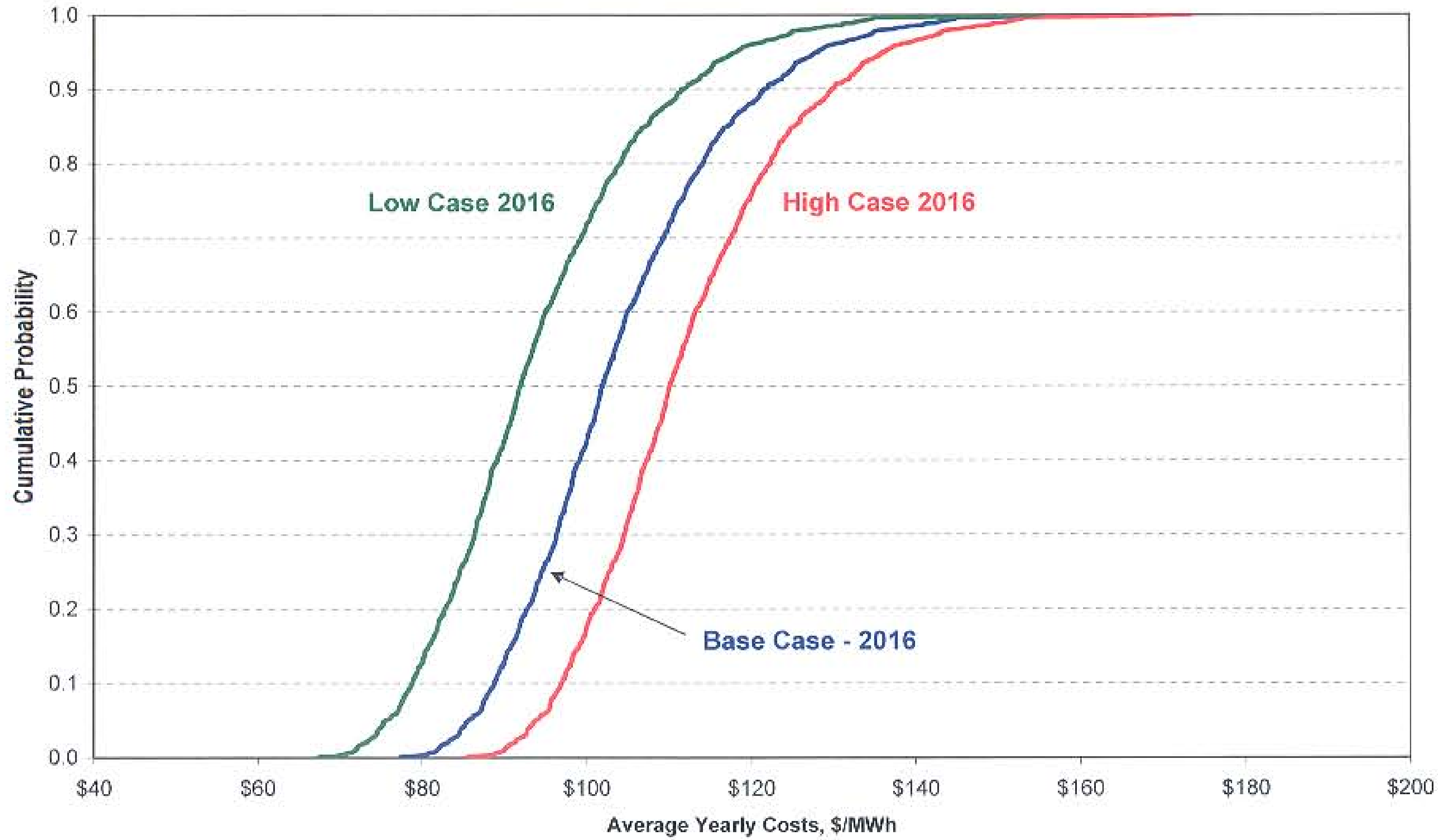
CT fixed costs shown as $/MWh for average output.

Figure 15: Comparative Risks of Market Portfolio Strategy Plus RECs, Green Wind and Bluewater in 2016



All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%.

Figure 16: Comparative Costs of Managed Portfolio Across Carbon/Gas/REC Sensitivity Cases



All strategies are modelled including deterministic price and load intraday patterns. 100MW Fixed upfront is 37% of total load and residual load procured through monthly DCA is roughly 53%.

Figure 17: Expected Costs for Alternative Procurement Strategies Across Carbon and Fuel Price Scenarios in 2016